The PUHCA has three essential elements, which are administered by the Securities and Exchange Commission (SEC). First, the SEC has the power to reorganize holding company structure according to standards set forth in the act. This task is essentially accomplished. The number of registered holding companies still subject to the act has been reduced from 200 to 12 through reorganization. Of these, three are gas utilities and nine are electric, the latter owning about 20 percent of private electric utility assets; the major part of the industry is, therefore, currently exempt from the act. The SEC now focuses on its two other major responsibilities under the act: the oversight of security issuances by holding companies to ensure proper capitalization of the companies and their subsidiaries, and supervision of mergers and acquisitions by both holding companies and exempt utilities engaging in interstate mergers.

The act's regulatory jurisdiction over interstate utility mergers might discourage such mergers by companies not now subject to regulation under PUHCA. The act has limited diversification by registered holding companies subject to its provisions by disallowing certain types of acquisitions. Generally, the PUHCA limits registered holding companies to diversifying in functionally related enterprises that are reasonably incidental or economically necessary or appropriate to the operations of a utility system. Utilities now exempt from SEC regulation also view the act as a threat to their diversification activities, however, since their exempt status can be withdrawn if such status is found to be no longer in the public interest. 6/

Proponents of liberalizing the PUHCA note that reducing SEC control over utility merger and diversification activities could provide utility management with greater flexibility to diversify holdings so as to yield significant benefits to investors. 7/ This flexibility is increasingly important given the slowdown in new plant construction and most utilities' improved cash-flow positions. If freed from PUHCA constraints, holding companies and exempt utilities could examine diversification alternatives and interstate mergers solely on their economic merits, rather than their regulatory implications. In addition, nonutility enterprises would no longer be discouraged from entry into the generation and transmission sector of the utility market by the PUHCA, which could add to competition in electricity supply. 8/

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6. See Donald Dulchinos and Larry Parker, *Electric Utilities: Deregulation, Diversification, Acid Rain, Tall Stack Regulation and Electric Demand Issues*, Congressional Research Service, IB85134 (July 29, 1985).

7. Current regulations already allow exempt utilities to create power generation subsidiaries without becoming subject to further regulation. See 17 Code of Federal Regulations 250.

8. Similar potential advantages are cited for proposals to deregulate other aspects of the electric utility industry. See, for example, P. Joskow and R. Schmalensee, *Markets for Power: An Analysis of Electric Utility Deregulation* (Cambridge, Mass.: MIT Press, 1983).

Those opposed to liberalization argue that these changes would encourage a diversion of capital and human resources from regulated to unregulated industries, possibly exposing customers of the regulated firm to increased costs from unregulated, risky investments or liens on regulated assets. In a review criticizing SEC proposals to repeal the PUHCA, the General Accounting Office also noted that doing so would have several adverse effects:

- States would lack jurisdiction over interstate holding companies and would be ill-equipped to oversee their interstate financial transactions;

- Approval of holding company acquisitions would no longer be required;

- Approval of securities issued by holding companies would no longer be regulated by SEC; and

- Allocations of service company costs (between operating and holding companies) would no longer be regulated. 9/

The GAO therefore recommended retention of SEC's role in reviewing the $11 billion in annual securities transactions of utility holding companies.

Liberalizing the holding company legislation would also have mixed results for ratepayers. While ratepayers could potentially benefit from lower capital costs achieved through successful company diversification, utility assets could also be used to finance unregulated, riskier lines of business, and result in higher electricity rates from losses and increases in capital cost.

Many state regulators are opposed to weakening or repealing the PUHCA, for they fear that they will be unable to regulate the complex interstate operations of holding companies without SEC oversight. 10/ Of particular concern is the possibility that holding companies could divert capital resources from state regulated utility operations to other, nonregulated activities, especially in the long term. But this outcome is quite uncertain, because even in the absence of PUHCA, states could still exercise considerable control over utility diversification. Other state officials

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9. See General Accounting Office, *Analysis of SEC's Recommendation to Repeal the Public Utility Holding Act*, RCED-83-118 (August 30, 1983).

10. See, for example, *Public Utility Holding Company Act Amendments*, Hearing before the Subcommittee on Energy Conservation and Power and the Subcommittee on Telecommunications, Consumer Protection and Finance, House Committee on Energy and Commerce, Serial No. 98-79, October 31, 1983.

suggest that the PUHCA should be strengthened, not repealed. For example, Governor Clinton of Arkansas argues that the SEC should be required to seek from state utility commissions an affirmative statement that security laws are either inapplicable to certain utility transactions or that a utility has complied with such laws. 11/ This would allow state regulators to approve construction plans by holding companies if a subsidiary operated within their state.

AMEND THE PUBLIC UTILITY REGULATORY POLICIES ACT

The Public Utility Regulatory Policies Act (PURPA) was passed in 1978 to encourage energy conservation and the development of alternative energy sources through changes to retail regulatory policies. Since its passage, PURPA appears to have stimulated the rapid development of customer-owned alternative power sources such as cogeneration. Cogeneration nationwide now produces at least 11,062 megawatts, and is expected to grow by another 10,000 to 50,000 megawatts by the 1990s. This added capacity may reduce the need for some utilities to build more power plants. 12/ At the same time, however, PURPA's requirements that utilities must buy power from all qualifying facilities in their franchise areas (while still retaining the obligation to provide backup power to cogenerators if it is needed) have complicated utilities' efforts to plan future capacity requirements. Utilities are currently prohibited from owning the majority share of a PURPA-qualifying facility. Allowing utilities such ownership rights could yield a number of benefits, including:

- Reducing capacity planning uncertainty by allowing greater utility control over the operation of cogeneration facilities;

- Increasing deployment of small modular power generating technology, particularly cogeneration; 13/ and

- Lowering customer rates.

Under current policy, ratepayers generally receive only the savings represented by the difference (if any) between the utility's avoided cost and

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11. See *Potential Impact of the Grand Gulf Nuclear Power Plant on Small Business*, Hearing before the Senate Committee on Small Business, December 7, 1984.

12. See Electric Power Research Institute, *1983 Utility Cogeneration Survey*, EPRI EM-3943 (April 1985); and Worldwatch Institute, *Electricity's Future: The Shift to Efficiency and Small Scale Power*, Paper #61 (November 1984). About 70 percent to 80 percent of this capacity is expected to use natural gas as a fuel source.

13. See Office of Technology Assessment, *Industrial and Commercial Cogeneration*, OTA-E-192 (February 1983).

the cogenerator's contracted selling price. 14/ If, on the other hand, the utility owned the facility, ratepayers could reap the full savings to the extent that actual power production costs were less than the avoided cost level.

Nevertheless, allowing utilities to own PURPA-qualifying facilities could reduce the number of cogeneration and alternative technology power projects pursued by nonutilities. 15/ Private companies could be wary of utilities controlling power production facilities inside their plants. Special regulations might also be needed to assure that utilities did not give preferred transmission access to their own cogeneration projects. Finally, the basis of state commission's determination of avoided cost levels could also change--to reflect the avoided costs of PURPA-qualifying power sources, rather than conventional baseload facilities--thereby reducing the potential profitability of non-utility PURPA projects.

PROMOTE FUEL NEUTRALITY IN UTILITIES' INVESTMENT CHOICES

A number of studies have asserted that certain federal regulatory and tax policies may distort the relative costs of alternative energy sources, leading to overall inefficiency in utilities' investment choices. 16/ Removal of these policies--thus allowing alternative fuels to compete more equally--could lower the costs of electricity generation to both ratepayers and federal taxpayers. Most prominent options in this regard are ending restrictions on the use of natural gas for electricity generation, restoring equal tax depreciation periods for nuclear and coal power plant investments, and changing the tax provisions that discourage mothballing partially completed power plants when cheaper alternatives become available.

Fuel Use Restrictions. The Powerplant and Industrial Fuel Use Act, enacted during the oil and natural gas shortages of 1978, generally prohibits the construction of new generating stations fueled by oil or natural gas. The deregulation of oil and gas markets, together with the recent dramatic reductions in the price of these fuels, suggests that these prohibitions be reconsidered. The removal of the gas restrictions--either outright or through a less restrictive policy on granting exemptions in power generation applica-

14. Avoided costs levels--which are established by state commissions and vary depending on whether the state seeks to encourage cogeneration--generally reflect the incremental costs to a utility of generating additional power.

15. This reduction may be more than compensated by expanded utility use of alternative energy sources. See Office of Technology Assessment, *New Electric Power Technologies* (July 1985).

16. See, for example, Rocky Mountain Institute, *A Preliminary Assessment of Federal Energy Subsidies in FY 1984*, testimony submitted to the Subcommittee on Energy and Agricultural Taxation, Senate Finance Committee, June 21, 1985; and Congressional Budget Office, *Energy Tax Expenditures: A Compendium*, Staff Memorandum (1981).

tions--could yield environmental benefits, stimulate interfuel competition, and encourage utility investments based on the economics of electricity production. In addition, removal of the natural gas restrictions could also improve the deployment opportunities for certain "clean coal" and solar technologies reliant on natural gas as an interim fuel. 17/ Removing the oil restriction as well would further increase interfuel competition, but would also leave the utilities and their customers more vulnerable to any future disruptions in oil supply.

Equal Tax Depreciation Categories. Another important federal policy that affects utility investment choices is the contrasting tax treatment of coal and nuclear power plants. Under the Accelerated Cost Recovery System (ACRS) adopted in the Economic Recovery Tax Act of 1982 (ERTA), coal power plant investments may be depreciated in 15 years, but nuclear plants have a tax life of just 10 years. Other things being equal, investing in nuclear power would, therefore, be preferable. Because ERTA's legislative history provides no specific reason for treating the two technologies differently and because both coal and nuclear power plants have relatively equal productive lifespans, amending the ACRS to eliminate this difference could help promote further fuel neutrality in utilities' investment choices. 18/

Tax Provisions for Uncompleted Plants. If demand growth proves lower than expected or less costly alternatives become available, the most economic course of action for a utility would be to cease construction of a partially completed plant. Current tax law, however, provides little incentive for utilities to mothball plants for later completion and use if needed. If a utility cancels a plant under construction, it obtains a tax write-off for a business loss. If it delays construction, however, it obtains no tax benefits. Allowing an abandonment loss deduction upon the mothballing of a plant with the repayment of tax if the plant is subsequently used, or restricting the imposition of state or local property taxes on mothballed plants could enhance this course of action. Savings from changes in the tax treatment of mothballed plants could easily be eroded, however, by the high carrying costs that would accrue by not completing the facility and entering it into the rate base.

INCREASE TRANSMISSION CAPABILITIES

Because of the excess generating capacity available in some parts of the United States, purchased power is often relatively inexpensive. Thus, many

17. See Office of Technology Assessment, *New Electric Power Technologies* (July 1985).

18. The President's proposed tax reform plan would, in fact, equalize the depreciation period for coal and nuclear plants. The plan would also increase, however, the depreciation period of smaller-scale generation plants to 10 years. Since the actual economic lives for smaller-scale facilities are considerably less than those of coal or nuclear plants, this change could discourage investment in these types of facilities, other things being equal.

utilities that foresee a need for additional power are seeking to increase their transmission access to available power rather than risking investment in new generation facilities. [19]/ Unfortunately, transmission service arrangements and capacity limitations on existing transmission lines sometimes preclude utilities from achieving the access they desire. From a national perspective, these inadequate transmission linkages lower efficiency by requiring many utilities to maintain higher reserve margins than they might otherwise need in order to ensure reliable service, especially during emergencies. Federal regulatory incentives that better allocate transmission over current lines or promote the construction of new transmission lines where these would be cost-effective might, therefore, lead to better regional or national efficiency. Substantial regulatory and physical impediments would need to be overcome, however, if such efforts were to be fully successful.

The National Electric Reliability Council (NERC) has identified a number of transfer areas that could benefit from new interconnections, such as the Pacific Northwest/California, Southwest/California, and Canada/Northeast. Physical limitations may limit the overall net benefits, however. [20]/ Moreover, without direct financial assistance (which would be extremely expensive) or an override of existing state authorities, federal powers to promote construction of new transmission lines are rather limited. Utilities constructing new lines are first subject to state laws applicable to siting and environmental protection. These regulations may inhibit new line construction especially if more than one states' requirements must be satisfied. Though the FERC may exempt electric utilities from any provision of state law "if the Commission determines that such voluntary coordination is designed to obtain economical utilization of facilities and resources in any area," doing so would risk severe political opposition. [21]/ Nor is it clear that federal authority can override state siting laws. Finally, the evidence indicates that utilities are pursuing new line construction without explicit

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19. The demand for wheeled electricity (transmission services provided by a utility on a prearranged basis to deliver power generated outside its own system to the system of another utility) has in fact increased more than 10 times in the last 20 years, and recent utility surveys confirm that this trend is likely to continue. Los Alamos National Laboratory, "The Future Market for Electric Generating Capacity: Technical Documentation," LA-10285-MS (March 1985); D. Bauer "An Investor-Owned Utility Perspective on Intersystem Energy Transfers and Wheeling Issues," Edison Electric Institute's presentation to National Association of Regulatory Utility Commissioners, (November 1984); Electric Edison Institute, "Transmission Access and Utilization Briefing Papers," (December 1984).

20. For example, recent Canadian power imports in the Northeast have adversely affected transmission readings as far south as the Carolinas and Virginia. See D. Bauer, "An Investor Owned Utility Perspective on Intersystem Energy Transfers & Wheeling Issue" Edison Electric Institute, November 27, 1984.

21. M. Cohen, "Efficiency and Competition in the Electric Power Industry," *Yale Law Journal* (1979).

support; fully 40 percent of planned utility investment, in fact, is now slated for transmission. Recognizing these problems and limitations, the FERC has instead issued a Notice of Inquiry to consider changing its regulatory policies in the long term. 22/

Federal efforts to equalize utility access to existing transmission lines would also have mixed effects on system efficiency. The FERC is not currently authorized under the Federal Power Act of 1935 to order a utility selling power in interstate commerce to interconnect with another firm, or to sell or exchange power with another utility. Without this authority, smaller utilities have felt that they lacked the leverage to participate in the regional economies of scale attained by the larger utilities forming power pools. To solve this access problem, it has been proposed that the Congress grant FERC the power to compel power transfers (known as "wheeling"). Mandatory transfers would enable any distributor to purchase power from any producer within economical transmission distance. It would facilitate reserve sharing and the exchange of economic energy and peak capacity reserves between systems that are not now interconnected.

Unfortunately, mandatory transfers would not encourage new investments in transmission lines, but merely reallocate the benefits derived from existing power transfers. Mandatory transfers could also make it difficult to plan future power system needs, and some cases diminish system efficiency because compelled linkages could affect the physical performances of existing transmission arrangements. And finally, utilities themselves have opposed mandatory wheeling. Their basic concern is the loss of their large, industrial customers, who would purchase their electricity generated by another system but still enjoy the security afforded by their utility's obligation to serve them on demand. In addition, utilities cite the complex planning and operational problems that could arise under any sort of common carrier scheme. 23/

Alternatively, the Congress could authorize the creation of regional power planning compacts to increase transfers in the industry. Such an approach would allow states to develop joint demand-supply forecasts and electricity import and export agreements. These agreements could also help eliminate inconsistencies among neighboring states' regulatory policies. Certain proposals, such as H.R. 3074, would also permit the regional compact to apply to the Federal Energy Regulatory Commission for an order to compel one or more electric utilities to provide or modify transmission services to meet regional requirements. 24/ The new regional planning enti-

22. U.S. Federal Energy Regulatory Commission, "Regulation and Electricity Sales--for Resale and Transmission Service," Docket No. RM85-17-000, Phases I and II (May 30, 1985).

23. Jerry Pfeffer, "Policies Governing Transmission Access and Pricing: The Wheeling Debate Revisited," *Public Utilities Fortnightly* (October 31, 1985).

24. H.R. 3074 was introduced by Representative Jeffords on July 24, 1985.

ties could also assume FERC's current powers to regulate purely intrastate wholesale sales of electricity.

Supporters of these proposals argue that regional planning would lead to more cost-effective electric service by encouraging the acquisition of new generation capacity and the use of existing resources according to regional needs. Large interstate utilities would face a less conflicting set of regulatory forces. In addition, multistate compacts could help create regional markets where electric suppliers would vie for customers.

Opponents of regional compacts contend that this approach would only create an unnecessary new layer of regulation, because states already have adequate statutory authority to coordinate their regulatory efforts when such efforts are cost-effective. Regional electricity markets could best be fostered not by increased regulation, but by phased deregulation of the generation sector of the industry. Opponents also believe that regional compacts' requests for mandatory power transfers should not be allowed to bypass the limits on third party access specified by the Federal Power Act. Finally, opponents object to proposals to transfer federal wholesale ratemaking authority partially to the states, preferring such powers to remain with the FERC. In this view, discretionary transfer of rate authority to the states could impede utilities' current voluntary coordination efforts.

APPENDIXES

APPENDIX A

CASH-FLOW EFFECTS OF AFUDC AND CWIP RATE TREATMENT

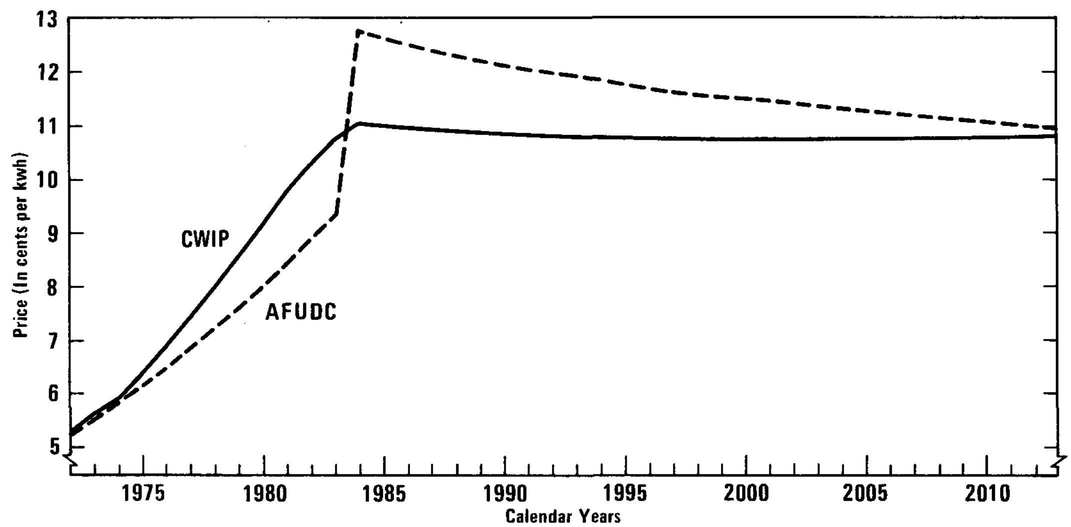
The important financial differences of cost treatment under construction work in progress (CWIP) and allowance for funds used during construction (AFUDC) can probably best be understood by considering a hypothetical utility that has a $1.5 billion (in 1984 dollars) rate base in 1972.[1] The average cost of electricity is 5 cents per kilowatt hour (kwh) in 1972. The firm begins construction of a nuclear plant that takes 12 years to build and becomes operational in 1984 at a cost of $3 billion. For simplicity, it is assumed that construction expenditures are made in 12 equal payments during the construction period. The firm is assumed to receive an allowed 13 percent real rate of return on its rate base. The new plant becomes operational in 1984. Consumption of electricity grows at 2.5 percent annually over the construction period.

The cost of building and generating power can differ considerably between the two accounting methods described here (see Figure A-1). During construction, electricity prices are higher with CWIP in the rate base because construction and financing costs are immediately passed on to the consumer. Conversely, an AFUDC account defers reimbursement of all construction and financing costs until the plant becomes operational; this keeps prices lower during construction but causes a sharp "spike" when the new plant comes on line. Starting at 5 cents per kilowatt-hour in 1971, electricity prices under CWIP treatment rise to almost 11 cents per kwh in 1983 compared with 9 cents per kwh with AFUDC pricing. When the plant becomes operational, however, prices rise to 13 cents per kwh in the AFUDC case, but remain virtually unchanged for the CWIP case. Allowing CWIP in the rate base can, therefore, prevent the occurence of "rate shock."[2]

1. The rate base is defined as the adjusted value of invested capital used and useful in rendering service to the public. The rate base includes generation, transmission, and distribution facilities providing service to consumers.

2. Rate base phase-in plans are also used to reduce rate shock. See discussion in Chapter III.

Figure A-1.
CWIP and AFUDC Price Paths



SOURCE: Congressional Budget Office.

NOTE: In this hypothetical example, $1.5 billion in operation and maintenence (O & M) costs (including depreciation) for electricity production and distribution in 1981 are assumed to increase at 8 percent a year until 1984. After 1984, the utility's O & M expenses plus those for a new plant are assumed to grow at 3 percent per year for the next 30 years (the life of the plant). Dividing costs by consumption provides an average cost of electricity supply that is assumed to equal price.

The net present value of revenue needs under each accounting option also differs considerably. 3/ Over the lifetime of the hypothetical plant, consumers would spend $500 million more for electricity with AFUDC pricing than with CWIP treatment, assuming a 9 percent discount rate. If the discount rate approaches the utility's cost of capital (assumed in this hypothetical case to be 13 percent), however, differences in consumers' expenditures become negligible. Consumers may, therefore, be indifferent about which pricing strategy is used, depending on investment conditions and the time value of money.

Arguments for CWIP pricing suggest that it may better approximate the true cost of providing new capacity than will AFUDC pricing and, as a result, provide appropriate investment incentives in the short run. As ex-

3. Present value measures in today's dollars the cost of a future expenditure or stream of expenditures. Such calculations take into account the time value of money: that is, a dollar available today is worth more than a dollar available in the future.

cess capacity dwindles and the new plant is being built, the marginal cost of providing power rises, since less efficient units typically are dispatched to meet demand. Electricity prices ought to reflect this when it occurs, if economic efficiency is to be achieved. From an investor's viewpoint, CWIP pricing is usually preferred to AFUDC pricing. An AFUDC discount does not add to a utility's cash flow, although it is treated as a component of a utility's total revenues. Thus, investors view increases in AFUDC as eroding the "quality" of a utility's earnings, making the utility a more risky investment. On the other hand, arguments against CWIP pricing suggest that it forces current consumers to subsidize future consumers.

APPENDIX B

DETERMINING WHICH INVESTOR-OWNED UTILITIES EXPERIENCED FINANCIAL STRESS

To identify those firms in financial difficulty, CBO examined financial data for 1983 and 1984 for 100 of the nation's largest investor-owned utilities. Using a fourfold screening process, 15 firms were identified as experiencing severe financial stress at that time (see Table 3 on p. 20). Five of the firms identified (Consumers Power, Long Island Lighting, Public Service of Indiana, Public Service of New Hampshire, and United Illuminating) were those with market-to-book ratios below .50. Middle South Utilities and Central Maine Power had market-to-book ratios of between 50 and 80 percent. Since September 1984, however, eight firms (Dayton Power & Light, Toledo Edison, Ohio Edison, Union Electric, Philadelphia Electric, Kansas Gas & Electric, Gulf States Utilities, and Kansas City Power & Light) have shown marked improvement by selling common stock at 80 percent or more of book value.

The screening process identifies financial stress--as indicated by intercompany comparisons of profitability, market performance, and liquidity--but it does not identify imminent bankruptcy.[1] This is because bankruptcy is not caused by a low market-to-book ratio or an inferior Standard & Poor's bond rating. Instead, bankruptcy occurs when financially weakened firms cannot absorb further cash-flow limitations, such as an unfavorable regulatory ruling or a drop in electricity demand. A firm could be included in more than one financial screen, yet still represent a low bankruptcy risk because external factors have stabilized.[2]

The CBO used four financial "screens" to avoid the shortcomings of using a single, arbitrary financial ratio (see Table B-1). The variables used

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1. "Financial stress" is an imprecise concept, evading rigorous definition. It generally refers to the ease with which external capital may be raised by a firm for necessary investment and maintenance of cash flow. It refers to the firm's current financial condition and anticipations of this condition in the future. For this analysis, firms in financial stress are firms that emerge in at least three of the four CBO screening procedures.

2. More sophisticated analytical methods, such as logit and discriminant analyses, could provide greater accuracy in predicting bankruptcy by using data from firms that actually have gone bankrupt. But, because utility bankruptcies have been rare, such a sample is not available.

TABLE B-1. FINANCIAL RATIO SCREENS USED TO IDENTIFY UTILITIES WITH LIQUIDITY CONSTRAINTS

Variable	Test Criteria	Description
	SCREEN A Total Number of Firms--32	
Working Capital Divided by Total Assets	Less than 0	Measure of net liquid assets relative to total capitalization. Liquid assets = current assets minus current liabilities
Retained Earnings Divided by Total Assets	Less than 4%	Measure of cumulative profitability.
Earnings Before Interest and Taxes Divided by Total Assets	Less than 65%	Measure of productivity of a utility's assets less tax and leverage factors.
Market Value Divided by Book Value of Total Debt	Less than 75%	Measure of how much a utility's assets can decline in value before liabilities exceed assets and insolvency develops.
Sales Divided by Total Assets	Less than 1%	Measure of capital turnover.
	SCREEN B Total Number of Firms--17	
Market Value Divided by Book Value of Common Stock	Less than 75%	Measure of how the financial community values the utility's future returns on common equity.
Rate of Return on Common Equity	Less than 11%	Measure of profitability of common equity.
Corporate Bond Rating	Less than BBB	Measure of long-term credit worthiness by Standard & Poor's.

(Continued)

TABLE B-1. (Continued)

Variable	Test Criteria	Description
SCREEN C Total Number of Firms--27		
Kidder, Peabody List of Utilities Facing Severe Capital Constraints (February 1984)	No specific financial measures	No financial ratios reported.
SCREEN D Total Number of Firms--18		
Market Value Divided by Book Value of Common Stock	Less than 75%	Measure of how the financial community values the utility's future returns on common equity.
Price Divided by Earnings of Common Stock	Less than $6	Measure of the stock market's value of a stock relative to a utility's profitability.
Estimated Total Construction Costs divided by Equity	Greater than 1	Measure of construction exposure.
Corporate Bond Ratings	Less than BBB	Measure of long-term credit worthiness by Standard & Poor's.

SOURCE: Congressional Budget Office.

in the four screens (A, B, C, D) were obtained from a variety of studies, and are generally well-accepted measures of market performance. Firm-specific quarterly data for 1983 and 1984 were used in the screenings. Only those firms appearing in at least three out of four screens were identified as financially weak (see Table B-2).

Screen A consists of five financial measures of liquidity, all found to be statistically significant indicators of financial weakness in other industries. [3] These include measures of working capital, retained earnings, earnings before interest and taxes, and sales relative to total assets, as well as the standard market value to book value of total debt. The cut-off criteria for this screen are listed in the second column of Table B-1. Thirty-two firms out of the 100 examined emerged in this screen.

Screen B is composed of financial ratios that appeared in a recent econometric analysis of financial health in the electric utility industry. [4] These three ratios are more illustrative of longer-term financial health than those found in screen A, but are often used by industrial analysts to select firms that may be particularly good investments. The criteria for poor performance include market-to-book stock ratio less than 75 percent, a rate of return on common equity less than 11 percent, and a corporate bond rating of BBB or less. Seventeen firms out of the 100 emerged in this screen.

Screen C, although without specific financial measures, is a list of utilities compiled by the investment banking firm of Kidder, Peabody & Co. [5] It lists 27 utilities that "have been unable to raise sufficient capital from the bond or stock markets to complete their nuclear plant construction." Total construction cost estimates are compared with debt outstanding, equity, commercial paper, and sunk cost in nuclear plants as a percent of common equity. The Kidder, Peabody report also examined sociodemographic characteristics of shareholders and creditors. The CBO used the 27 listed firms as Screen C.

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3. Edward Altman, "Financial Ratios, Discriminant Analysis and the Prediction of Corporate Bankruptcy," *The Journal of Finance*, vol. XXIII, No. 4 (September 1968).

4. U.S. General Accounting Office, "Analysis of the Financial Health of the Electric Utility Industry" (June 11, 1984).

5. Eugene Meyer, "The Nuclear Utility Industry is Dead! So What? Should it be Revived?" Kidder, Peabody & Co., February 15, 1984.

TABLE B-2. UTILITIES IN FINANCIAL DISTRESS, 1984

Firm	Screen A	Screen B	Screen C	Screen D	Total
Central Maine	--	x	x	x	3
Consumers Power	x	x	x	x	4
Dayton Power & Light	x	x	x	x	4
Gulf States Utilities	x	x	x	x	4
Kansas City Power and Light	x	x	x	x	4
Kansas Gas & Electric	x	x	x	x	4
Long Island Lighting	x	x	x	x	4
Middle South Utilities	x	x	x	x	4
Ohio Edison	x	x	x	x	4
Philadelphia Electric	x	x	x	x	4
Public Service of Indiana	x	x	x	x	4
Public Service of New Hampshire	x	x	x	x	4
Toledo Edison	x	x	x	x	4
Union Electric	x	x	--	x	3
United Illuminating	x	x	x	x	4

SOURCE: Congressional Budget Office.

Screen D compares construction costs accumulated by utilities relative to their equity values. It also includes the price earnings ratio as an additional valuation measure. Eighteen firms appeared in this screen.

In this report, utilities were considered financially stressed if their quarterly ratios fell within the criteria of at least three of the four screens at any time in the four quarters of 1983 and the first three quarters of 1984. Table B-2 displays the results.